Well Completion Report PG&E CAES Injection/Withdrawal Well and Observation Wells

In Accordance with EPA Form 7520-9

PG&E Compressed Air Energy Storage Project
Compression Testing Program
King Island Gas Field, San Joaquin County, California

~~November 25~~December ~~9~~10, 2014

Pacific Gas and Electric Company®

CERTIFICATION

This report has been prepared under the review and supervision of Mark Ausburn, P.G., as an employee of WorleyParsons and with expertise in petroleum geology. The report has been prepared with the assistance of Michael Tietze, C.E.G, as an employee of Jacobson James & Associates, and with expertise in engineering geology and deep well hydrology; Saeed Irani, P.E., as an employee of Irani Engineering and with expertise in petroleum engineering and injection well drilling and design; and Alan Burzlaff, P.E., as an employee of MHA Petroleum Consultants and with expertise in petroleum engineering and reservoir engineering. Their signatures and stamps appear below.

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EPA FORM 7520-9 ATTACHMENTS

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I. Geologic Information

1. *Lithology and Stratigraphy*

A. *Provide a geologic description of the rock units penetrated by name, age, depth, thickness, and lithology of each rock unit penetrated.*

The geologic description of rock units provided in **Table I-1** below is based on geological data from the PG&E Test Injection/Withdrawal Well 1 (I/W Well), including borehole geophysical logs (also referred to as electric logs or e-logs), mud log and sidewall core (SWC) analyses, supplemented with information from the PG&E core well drilled at King Island in March 2013 (Piacentine 2-27) due to its close proximity to the I/W Well (360 feet between top of Mokelumne River Formation [MRF] borehole intersection points). Formation depths and thicknesses are from I/W Well geophysical logs, based on correlations with nearby King Island Gas Field wells (primarily Piacentine 1-27 and Piacentine 2-27). The regional formation markers upon which formation tops and thicknesses in **Table I-1** are based are in accordance with the regional stratigraphic framework presented in Edmondson, W.F. and others (1967).

Formation lithology descriptions are based on information from the I/W well e-logs, mud log and sidewall cores, and are supplemented with lithologic information from the Piacentine 2-27 conventional core.

The top of the MRF was penetrated at a sub-sea depth of 4,650 feet (Table I-1), approximately 23 feet high to the pre-drill estimated depth, approximately 11 feet high to the top of the MRF in the Piacentine 1-27, and approximately 26 feet high to the top of the MRF in the Piacentine 2-27.

Table I-1: Description of Rock Units

Formation	Sub-Unit	Age	Depth to Top (feet)			Thickness (feet)		Lithology and Depositional Environment
			MD	TVD	SS	MT	TVT	
Flood Plain Deposits		Pleistocene to Recent	0	0	-8	460	460	Coarsening-upwards sand dominated alluvial/fluvial sequence, with clay layers dominant at base of sequence. Sands are fine to coarse grain and poorly-sorted. Some sand has "salt & pepper" appearance. Occasional igneous and metamorphic fragments.
Laguna Formation		Pliocene to Pleistocene	460	460	-452	640	640	Stratified alluvial/fluvial sand-claystone sequence, with interbedded sand layers becoming thicker towards the base of the sequence. Sands are fine to coarse grain and poorly-sorted; some with "salt & pepper" appearance. Cobble congomerate layers near top of sequence. Occasional igneous, metamorphic and mafic volcanic lithic fragments. Claystones are friable.
Mehrten Formation		Late Miocene to Pliocene	1100	1100	-1092	2250	2250	Stratified shallow-marine sand, siltstone, claystone sequence. Sands are fine-grain and well-sorted and have calcareous cement. Fossil shells between approximately 1400 and 1600 feet depth. Occasional lithic fragments change from mostly igneous and metamorphic above 1700 feet depth to mostly mafic volcanic below 1700 feet depth, suggesting a change in in the provenance of the sands. Claystones are friable.
Markley Formation		Late Eocene	3350	3350	-3342	332	331	Stratified marine mudstone, siltstone, sandstone sequence, with interbedded sandstone layers comprising approximately 20% of sequence. Sandstones are silty, very fine to fine-grain, well sorted and friable. Siltstones and sandstones have calcareous cement. Occasional multi-colored lithic fragments.
Nortonville Shale		Eocene	3682	3681	-3673	100	99	Regional marine shale deposit. Shale is firm to friable, sometimes sandy or silty and has bathyal microfauna. Sequence includes minor siltstone/sandstone interbeds.
Domengine Formation		Middle Eocene	3782	3780	-3772	878	832	Stratified marine sandstone sequence with thin interbeds of shale and siltstone. Blocky sandstone layers are well sorted, clean and mostly very fine to fine grain in the upper portion of the sequence; with increasing coarse grain sand layers, volcanic and mafic fragments and black lignite towards the base. Occasional micro and mega-fossil fragments.
Capay Shale		Eocene	4660	4612	-4604	49	46	Regional marine shale deposit consisting predominately of dark greenish to gray claystone with common scattered large (to 1") pyrite nodules and occasional mollusk fragments. Conglomeratic in basal 5-ft with abundant glauconite.
Mokelumne River Formation	King Island Gas Reservoir	Upper Cretaceous	4709	4658	-4650	142	135	Interlayered sand and mudstone, comprised of 3 sand lobes and 2 intervening mudstone layers of approx. 16 and 12 feet thickness. Sand is predominantly medium-grained, friable, with common cross-laminations defined by biotite and carbonaceous material. Small igneous and lignite fragments; trace of kaolite and glauconite.
	Sub-Reservoir Shale		4851	4793	-4785	49	46	Shale and mudstone with occasional very fine-grained sand.
	MR2		4900	4839	-4831	NR	NR	Based on electric log character and mud log description, lithology similar to King Island Reservoir. Very fine to fine-grain sand. Trace pyrite.

Definitions

KB = kelly bushing
MD = Measured Depth; from rig kelly bushing
MT = Measured Thickness
NR = Total thickness not reached
SS = Subsea elevation; relative to mean sea level
TVD = True Vertical Depth; from rig kelly bushing
TVT = True Vertical Thickness
ft = Feet

Datums

Ground	elev.	-3.75	ft relative to mean sea level
KB	height	12	ft above ground surface
KB	elev.	8.25	ft relative to mean sea level

B. *Provide a description of the injection unit.*

The injection zone description provided in **Table I-2** below is based on data from the I/W Well, including borehole geophysical logs, mud log, SWC analyses, pressure and temperature gauge measurements and step rate test/fall-off test (SRT/FOT) analysis; supplemented with the Piacentine 2-27 conventional core lithologic descriptions (see Table footnotes for more detail). Injection zone depth and thickness are from I/W Well geophysical logs, based on correlations with nearby King Island Gas Field wells (primarily Piacentine 1-27 and Piacentine 2-27). The injection zone is from the top of the under-reamed (to 17” diameter) and gravel packed interval at 4722’ measured depth (MD) (4671’ true vertical depth [TVD]) to the bottom of the gravel pack at 4815’ MD (4759’ TVD).

Table I-2: Description of Injection Zone

Formation	Injection Zone	Age	Lithology	Depth to Top (feet)			Interval Thickness (feet)		Net Reservoir Thickness (feet)		Avg. Porosity (%) [1]	Avg. Permeability (mD) [2]	Bottom Hole Temperature (Deg. F) [3]	Bottom Hole Pressure (psi) [4]	Fracture Pressure (psi) [5]	Formation Fluid Pressure (psi) [6]	Formation Fluid Pressure Gradient (psi/ft) [6]
				MD	TVD	SS	MT	TVT	MT	TVT							
Mokelumne River Formation	King Island Gas Reservoir	Upper Cretaceous	Interlayered sand and mudstone, comprised of 3 sand lobes and 2 intervening mudstone layers of approx. 16 and 12 feet thickness. Sand is predominantly medium-grained, friable, with common cross-laminations defined by biotite and carbonaceous material. Small igneous and lignite fragments; trace of kaolite and glauconite.	4722	4671	-4663	93	88	60.25	57	31	140	147	1931	3758	1908	0.4057

Definitions

Deg. F = Degree Fahrenheit
KB = kelly bushing
MD = Measured Depth; from rig kelly bushing
mD = Milli-Darcy
MT = Measured Thickness
psi = Pounds per square foot
PB = Plug-back depth
TVD = True Vertical Depth; from rig kelly bushing
TVT = True Vertical Thickness
SS = Subsea elevation; relative to mean sea level
ft = Feet

Footnotes

1 From I/W well sidewall core analyses
2 From I/W well Falloff Test (FOT)
3 From I/W well electric log header
4 Based on PB depth (TVD) and pressure gradient established by RDT discrete depth pressures
5 From I/W well Step Rate Test (SRT), corresponding to Instantaneous Shut-in Pressure (ISIP)
6 Measured in I/W well with Halliburton's Reservoir Description Tool (RDT); average across interval

Datums

Ground	elev.	-3.75	feet relative to mean sea level
KB	height	12	feet above ground surface
KB	elev.	8.25	feet relative to mean sea level

C. *Provide chemical characteristics of formation fluid (attach chemical analysis).*

~~*Formation water sampling and analysis pending I/W Well completion scheduled for November 20-25, 2014.*~~Two water samples were collected from the injection zone on November 26, 2014 using nitrogen injection through a 2" coil tubing at an estimated depth of 4,830 feet to induce formation water flow. The nitrogen was injected slightly below the I/W well screen interval, which extends from approximately 4,686' to 4,809' MD. The nitrogen lift operation was initiated at 09:30 and was completed at 13:30 after recovering approximately 355 barrels of formation water.

During the operation, the produced water was monitored using a YSI 556 multi-probe water quality meter to record pH, specific conductance, dissolved oxygen, temperature, and oxidation-reduction potential (ORP). Presence of formation water was determined through monitoring until the field parameters stabilized within 10% of three successive readings at five-minute intervals. During this process, visual observations of the produced water were also made and recorded on field data sheets. These observations include notes regarding the turbidity, color, and consistency of the produced water. Field data sheets including visual observations of the produced water and field parameter readings during the nitrogen lift are included in **Appendix I-1**.

Using the nitrogen lift program, the well was unloaded at an average rate of approximately 1.5 barrels per minute (BPM) over a 4-hour period. After approximately 266 barrels of fluid was unloaded from the well, the stabilization criteria were met and an initial water sample was collected at 12:45. A duplicate sample was collected approximately 15 minutes prior to the end of the nitrogen lift at 13:15 (after an estimated 333 barrels were removed). The nitrogen lift operation was stopped at 13:30 after approximately 355 barrels of fluid was unloaded from the well and the turbidity had been significantly reduced. The final field parameters were recorded on the field sampling form (**Appendix I-1**) and are summarized in the table below:

Table I-3: Final Field Parameter Readings

Time	pH	Specific Conductance (µS/cm)	Dissolved Oxygen (mg/L)	Temperature (degrees Celsius)	ORP (mV)
12:30	7.27	37497	0.84	32.73	-158.1

Notes:
µS/cm = microsiemens per centimeter
mg/L = milligrams per liter
mV = millivolts
ORP = oxidation-reduction potential

The samples were placed in laboratory-provided bottles, properly labeled, packaged, and delivered under chain of custody protocol (**Appendix I-2**) to McCampbell Analytical, Inc. in Pittsburg, California for analysis of Trace Metals, Alkalinity, Conductivity, Hardness, Total Dissolved Solids (TDS), Specific Gravity, and Oil and Grease, as specified in the EPA Permit (Part II, Section B.3.a). In addition, the following analytes were analyzed by the laboratory: Total Petroleum Hydrocarbons (TPH; as gasoline, diesel, and motor oil), Cations and Anions, Total Organic Carbon (TOC), and Total Suspended Solids (TSS). The duplicate sample was placed on "Hold" pending analysis of the initial sample.

After the initial sample results were received, the duplicate sample was analyzed for TDS, potassium, sodium and chloride to confirm the degree of formation purging as discussed further below. A complete laboratory analytical report is provided in **Appendix I-2**.

The laboratory analytical results for the initial sample indicate that the water sample contained potassium at a significantly higher concentration than the Mokelumne River Formation injection zone water sample collected from the Piacentine 2-27 well on March 26, 2013[1] (7,300 vs 33 mg/L). The Piacentine 2-27 well penetrates the Mokelumne River Formation approximately 350 feet southwest of the I/W Well Mokelumne River Formation intersection (**Appendix II-2**). It was concluded that the high potassium concentration in the I/W Well water samples is associated with residual potassium chloride (KCl) water remaining in the formation after the Step Rate Test (SRT) conducted on October 27, 2014, during which almost 2,500 barrels of 4% KCl water was injected into the formation (see SRT/FOT Report in **Appendix V-6b**). To confirm this interpretation, the duplicate sample was analyzed for TDS, potassium, sodium and chloride. The potassium concentration detected in the duplicate sample was also significantly higher than in the formation water sample collected from the Piacentine 2-27 well, but slightly lower than in the initial sample. This finding is consistent with the slow progressive purging of KCl water from the formation during the nitrogen lift operation.

Based on these results, the concentration of residual KCl in the formation water was calculated as shown in **Appendix I-3**. The table below summarizes the concentration of potassium in the samples and the calculated residual KCl concentration, and compares these results to the RDT water sample collected on March 26, 2013 from the Piacentine 2-27.

Table I.4: Selected Water Sample Analytical Results and Calculated Solute Concentrations in Formation Water

Analyte	Piacentine 2-27 Sample	Initial I/W Well Sample	Duplicate I/W Well Sample
Potassium (mg/L)	33	7,300 (assumed 33 in Formation Water)	6,600 (assumed 33 in Formation Water)
Residual KCL (%)	0	34.8 (calculated)	31.5 (calculated)

Notes:
mg/L = milligrams per liter
KCl = potassium chloride
% = percent

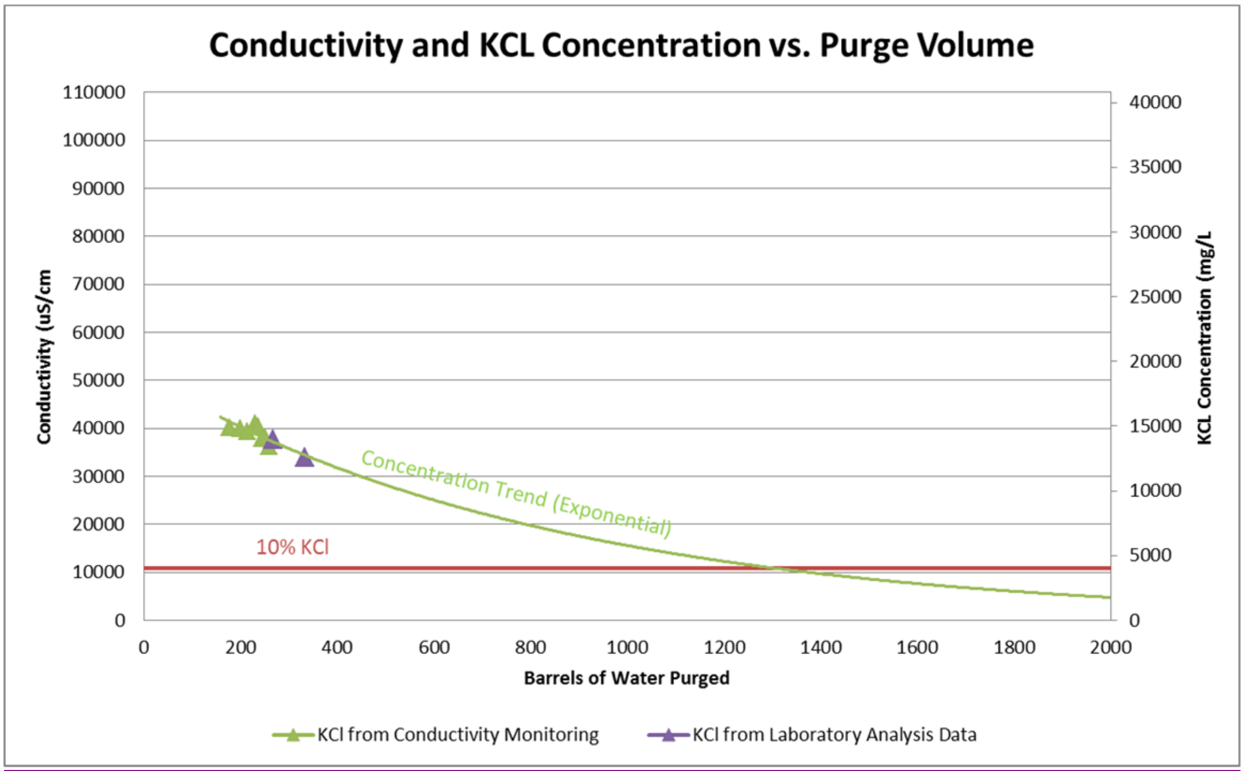
As shown in the table above, significant residual concentrations of KCl water ranging from 31.5 to 34.8 percent were still present in the formation at the time of sampling. As such, these samples are not as representative of formation chemistry as the injection zone water sample collected from the Piacentine 2-27, which was drilled and sampled in March 2013, over 18 months before 4% KCL water was introduced into the injection zone.

In order to investigate the volume of water that would need to be purged from the well to collect a representative formation water sample, the estimated KCl concentration during purging (assumed to be

[1] A discrete depth *in-situ* water sample was collected from the injection zone in the Piacentine 2-27 at a depth of 4,774' MD using Halliburton's Reservoir Description Tool (RDT).

proportional to sample specific conductance) as well as the laboratory derived KCl concentrations in the initial and duplicate samples were plotted on a chart. A best-fit line was added to the data based on an exponential function and plotted forward to the water volume that would need to be pumped from the well to achieve adequate purging for collection of a representative formation water sample. The chart below indicates that at the measured trend, approximately 1,300 barrels of fluid would need to be pumped from the formation to reach a residual KCL concentration of 10% (4,000 mg/L, which is 10% of KCL concentration of 4%), and approximately 2,000 barrels of fluid would need to be purged to achieve 5% residual KCl. Based on the logistical and economic constraints of the project, management of such large volumes of purge water at the Site is not feasible.

Figure I-1: Calculation of Purge Volume vs Residual KCl Concentration in Formation



Although the water samples collected from the I/W Well are not considered representative of formation fluid chemistry, the sample collected from Piacentine 2-27 was collected prior to the SRT and is considered representative of formation water chemistry. This sample was collected from the Mokelumne River Formation at a lateral distance of approximately 350 feet from the I/W Well injection zone intersection. Complete analytical results for the Piacentine 2-27 sample, including all analytes required under the UIC permit for the project, are included in **Appendix I-4**.

D. *Provide a description of freshwater aquifers*

Freshwater aquifers are defined by the United States Environmental Protection Agency (US EPA) as groundwater-bearing zones with ~~Total Dissolved Solids (TDS)~~TDS of less than 10,000 milligrams per liter (mg/L; equivalent to parts per million or ppm), and are called Underground Sources of Drinking Water (USDW). The State of California defines freshwater aquifers as groundwater bearing zones with TDS of less than 3,000 (mg/L)[2]. The EPA definition of a freshwater aquifer is assumed for this document, and to avoid confusion, these aquifers are herein referred to as USDW aquifers. A geologic description of USDW aquifers is provided in the second subsection below.

(1) *Depth to base of fresh water (less than 10,000 mg/L TDS).*

Based on TDS values derived using spontaneous potential log (SP) method formulas (listed in **Table I-~~3~~5** below), the base of USDW (less than 10,000 mg/L TDS) at the I/W Well occurs at an interpolated depth of 2,382 feet in Plio-Miocene sediments of the Mehrten Formation. This is shallower than the previously calculated depth to the base of USDW in wells within the Area of Review (AOR) presented in Attachment E of the Underground Injection Control (UIC) permit application (PG&E, 2014) in which TDS values >10,000 ppm first occur in the upper portion of the Domengine Formation at interpolated depths ranging from 3,878 to 4,002 ppm (PG&E, 2014; Table E-3 and Figure D-6). This may reflect a local variation in the depth of USDW, or possibly be due to a faulty (too high) R_{mf} measurement in the I/W Well. We recommend that the base of USDW depths in the other AOR wells be utilized as they are more conservative and more likely to be representative of regional conditions.

The Excel spreadsheet with active cells and formulas from which the Table below was copied, and that was used to calculate TDS concentrations and the depth to the base of USDW in the I/W Well, is included on the data CD with this report.

[2] California State Water Resources Control Board (SWRCB) Resolution 88-63 assigns groundwater resources containing up to 3,000 milligrams per liter (mg/L) of total dissolved solids (TDS) a potential beneficial use as drinking water. Similarly, the California Department of the Interior, Division of Oil Gas and Geothermal Resources (DOGGR) classifies freshwater as containing less than 3,000 mg/L TDS. These freshwater aquifers are a subset of USDW.

Table I-~~3~~5: TDS and Depth to Base of USDW (<10,000 mg/L TDS) in Aquifers

Well	Data from Log Header Used in TDS Calculations		Depth (TVD in feet)	Spontaneous Potential (millivolts)	Formation Temperature (deg C)	Formation Temperature (deg F)	Resistivity of Mud Filtrate (Ohms-m^2/m)	Equivalent Resistivity of Formation Water (Ohm-m^2/m)	Resistivity of Formation Water (Ohm-m^2/m)	Resistivity of Formation Water at 400F (Ohm-m^2/m)	Calculated TDS of Formation Water (ppm)	Interpolated Depth to Base of USDW (feet)	Comments
A	B	C	D	E	F	G	H	I	J	K	L		M
PG&E Test Injection\ Withdrawal Well 1 (Surface casing Interval)	Rm (Ohm-m^2/m) at 73°F	3.5	307	-34.0	19.0	66.1	3.42	0.94	1.75	0.31	3,388		
	Rmf (Ohm-m^2/m) at 70°F	3.25	547	-42.0	21.3	70.3	3.24	0.69	1.03	0.20	5,534		
	Rm (Ohm-m^2/m) at BHT	2.31											
	Rmf at BHT	3.18											
	Total Depth (ft)	631											
PG&E Test Injection\ Withdrawal Well 1 (Surface casing shoe to Total Depth)	Rm (Ohm-m^2/m) at 62°F	3.5	730	-27.0	23.1	73.5	2.40	0.84	1.52	0.30	3,534		
	Rmf (Ohm-m^2/m) at 58°F	2.98	888	-32.0	24.6	76.3	2.32	0.70	1.10	0.22	4,786		Rmf @ BHT calculated using Schlumberger Gen 6 (Column H formula)
	Rm (Ohm-m^2/m) at BHT	1.57	965	-34.0	25.3	77.6	2.29	0.64	0.97	0.20	5,365		
	Rmf at BHT	1.26	1,350	-44.0	29.1	84.3	2.12	0.44	0.55	0.12	9,031		
	BHT (°F)	147	1,597	-39.0	31.5	88.6	2.02	0.50	0.68	0.16	6,832		
	BHT (°C)	63.9	1,875	-43.0	34.1	93.5	1.93	0.42	0.54	0.13	8,247	2,382	
	Total Depth (ft)	4950	2,983	-53.0	44.9	112.7	1.61	0.27	0.32	0.09	12,078		
			3,530	-57.0	50.2	122.3	1.50	0.23	0.26	0.08	13,685		
			4,070	-68.0	55.4	131.7	1.39	0.16	0.17	0.06	20,182		
			4,674	-68.0	61.2	142.2	1.30	0.15	0.17	0.06	19,157		
			4,788	-62.0	62.3	144.2	1.28	0.18	0.21	0.08	15,086		
			4,869	-66.0	63.1	145.6	1.27	0.16	0.18	0.07	17,487		

Average mean air temperature in °C (Sacramento, CA): 16
http://www.allcountries.org/uscensus/408_normal_daily_mean_temperature_selected_cities.html

Abbreviations
BHT = Bottom hole temperature
deg C = Degrees Celsius
deg F = Degrees Fahrenheit
SSP = Static spontaneous potential (millivolts)
FD = Formation depth of interest
FT = Formation temperature at depth of interest
K_c = Electrochemical sponteneous potential coefficient
MD = Measured depth in feet from drill rig kelly bushing
MST = Mean surface temperature
Ohm-m^2/m = Ohm-meters squared per meter
ppm = parts per million
R_m = Resistivity of mud (Ohm-m^2/m)
R_{mf} = Resistivity of mud filtrate (Ohm-m^2/m)
R_{mfeq} = Equivalent mud filtrate resistivity (Ohm-m^2/m)
R_{mc} = Resistivity of mud cake (Ohm-m^2/m)
R_W = formation water resistivity
R_{weq} = Equivalent water resistivity
T = Temperature
TDS = total dissolved solids
USDW = Underground sources of drinking water
TVD = Vertical depth in feet from drill rig kelly bushing

Formulas ***(Source)***
Column F: FT (deg C) = (((BHT - MST) / well total depth)) * FD) + MST
Column G: FT (deg F) = (deg C * 9/5) + 32
Column H: R_{mf} at FT = R_{mf} at measurement T * [(measurement T + 6.77) / FT + 6.77)] *(Source: Schlumberger chart Gen-6)*
Column I: R_{weq} = 0.85 * Rmf * 10^SSP / (60.5 + 0.133 * FT); incorporating the following equations:
R_{mfeq} = 0.85 * R_{mf}@FT (when R_{mf}@75 > 0.1) *(Source: Schlumberger chart SP-1)*
SSP = -K_c * log(R_{mfeq} / R_{weq}) *(Source: Schlumberger chart SP-1)*
K_c = 60.5 * 0.133 * FT *(Source: Ransom)*
Column J: Empirical solution to Schlumberger chart SP-2, providing R_W from R_{weq} at FT.
Column K: R_w at 400 deg F = R_w at FT * [FT + 6.77) / 400 + 6.77)] *(Source: Schlumberger chart Gen-6)*
Column L: Empirical solution to Schlumberger chart Gen-6, providing TDS from R_w at 400 deg F.

(2) *Provide a geologic description of aquifer units with name, age, depth, thickness, lithology and average Total Dissolved Solids (TDS).*

Since there are numerous individual saturated sands above the base of USDW, the USDW interval has been divided into the sand packages presented in **Table I-**4**6** below. These sand packages are separated by intervals consisting mostly of silts and clay (or siltstone and shale). The sand packages were defined based on SP and/or gamma ray log character. Aquifer lithology descriptions are based on I/W Well SP and gamma ray log character and I/W Well mud log lithologic descriptions. TDS values are based on analysis of the SP log from the I/W Well, supplemented for shallow Flood Plan Deposits by TDS concentrations from the National Water Information System database (NWIS; USGS, 2013).

The USDW aquifers listed in **Table I-**4**6** are in accordance with the interpretation presented in Section 1.D(1) above in which the base of USDW occurs in the upper portion of the Domengine Formation. The deepest USDW aquifer is the uppermost sand in the Domengine Formation.

Table I-46: Description of USDW Aquifers

Formation	Age	Depth Range (feet) [1]		Thickness (feet)	TDS Range (ppm)		TDS Average (ppm)		Lithology
		MD (TVD)	SS (TVD SS)	MT (TVT)	Laboratory [2]	SP Method[3]	Laboratory	SP Method	
Flood Plain Deposits	Pleistocene to Recent	0 to 455	-8 to -447	455	427 - 1640	3388	779	3388	Coarsening-upwards sand dominated alluvial/fluvial sequence, with clay layers dominant at base of sequence. Sands are fine to coarse grain and poorly-sorted. Some sand has "salt & pepper" appearance. Occasional igneous and metamorphic fragments.
Laguna Formation	Pliocene to Pleistocene	460 to 1000	-452 to -992	540	--	3534 - 5534	--	4618	Stratified alluvial/fluvial sand-claystone sequence, with interbedded sand layers becoming thicker towards the base of the sequence. Sands are fine to coarse grain and poorly-sorted; some with "salt & pepper" appearance. Cobble congomerate layers near top of sequence. Occasional igneous, metamorphic and mafic volcanic lithic fragments. Claystones are friable.
Mehrten Formation	Late Miocene to Pliocene	1160 to 1620	-1152 to -1612	460	--	6832 - 9031	--	7932	Stratified shallow-marine sand, siltstone, claystone sequence. Sands are fine to very fine grain and well-sorted and have calcareous cement. Fossil shells between approximately 1400 and 1600 feet depth. Occasional lithic fragments change from mostly igneous and metamorphic above 1700 feet depth to mostly mafic volcanic below 1700 feet depth, suggesting a change in in the provenance of the sands. Claystones are friable.
		1780 to 2410	-1772 to -2402	630	--	8247	--	8247	
		2900 to 3350	2892 to 3342	450		12078		12078	
Markley Formation	Late Eocene	3423 to 3682	2415 to 3674	259		13685			Stratified marine mudstone, siltstone, sandstone sequence, with interbedded sandstone layers comprising approximately 20% of sequence. Sandstones are silty, very fine to fine-grain, well sorted and friable. Siltstones and sandstones have calcareous cement. Occasional multi-colored lithic fragments.
Domengine (upper-most sand)	Middle Eocene	3782 to 3850 (3780 to 3847)	3774 to 3842 (3772 to 3839)	68 (67)		NA[4]		NA[4]	Fine to very fine grained sand with clay, siltstone and mafic fragments. Occasional shell fragments.

Definitions

MD = Measured Depth; from rig kelly bushing

MT = Measured Thickness

TVD = True Vertical Depth; from rig kelly bushing

TVT = True Vertical Thickness

SS = Subsea elevation; relative to mean sea level

SP = Spontaneous Potential

ppm = Parts Per Million

-- = Data not available.

Footnotes

1 Depth ranges of potential USDW sand "packages", each with multiple individual water saturated sand bodies.

2 TDS concentration from NWIS (USGS, 2013); as presented in Table E-2 of June 2014 UIC Permit Application, in wells drilled to depths of 33 to 142 feet, with lowest and highest TDS value outliers omitted in range.

3 TDS concentrations from SP method using I/W Well SP curve and data. I/W Well TDS concentrations appear to be biased high compared to TDS concentrations calculated using data from other wells in AOR, as discussed in Section 1.D(1).

4 Not available. Sand too shaly to allow valid TDS calculation using SP method.

References

Edmondson, W.F. and others, 1967, Correlation Section, Sacramento Valley, Suisun Bay to Lodi, California: Pacific Section Amer. Assoc. of Petroleum Geologists, Correlation Section 15.

PG&E, 2014. Underground Injection Control Permit Application Technical Attachments, PG&E Compressed Air Energy Storage Project Compression Testing Program, King Island Gas Field, San Joaquin County, California, Revised April 18, 2014.

United States Geological Survey (USGS) (2013), National Groundwater Information System, *http://waterdata.usgs.gov/nwis*

II. Well Design and Construction

The I/W Well was spud on October 8, 2014 and drilled to a total depth (TD) of 4,963 feet MD (4950' MD based on wireline logs). After the borehole was logged to TD, it was plugged back to 4815' MD and 9-5/8" casing was set and cemented to 4716'. The interval from 4722' to 4815' MD was under-reamed to 17" and completed with gravel pack and 5-1/2" liner with wire wrapped screen (WWS) to 4814' MD. The drilling rig was released on November 4, 2014 and the well was temporarily suspended pending installation of tubing, packer and well head using a workover rig (planned for November 20-25, 2014).

A Division of Oil, Gas and Geothermal Resources (DOGGR) Well Summary Report (**Appendix II-1a**) and History of Oil or Gas Well (**Appendix II-1b**) were prepared for the I/W Well~~ *for the Department of Oil, Gas and Geothermal Resources (DOGGR) will be prepared immediately after the well is completed, scheduled for November 20-25, 2014.*~~. ~~"As-build" construction details for the I/W Well are provided in the series of tables below~~The DOGGR reports provide well construction details and a chronological narrative summary of the well drilling, logging, testing, completion and stimulation activities.

"As-build" construction details for the I/W Well are provided in the series of tables below. General details of the well are provided in Table II-1 below. A figure depicting the location of the I/W Well as well as the two observation wells is provided in **Appendix II-2**.

Table II-1: General Details for I/W Well

API No.	7720739
Surface Location Coordinates (Lat-Long)	38.081988814 121.422161054 (NAD 83)
Spud Date	8-Oct-14
Rig Release Date	4-Nov-14
Surface Elevation (ft MSL)	-3.75'
KB Elevation (ft MSL)	8.25'
Total Drilled Depth (ft MD)	4963'
Total Wireline Logger Depth (ft MD WL)	4950'
Completed Well Depth (ft MD)	4815'

Definitions
ft MD = Measured depth below Kelly Bushing in feet
ft MD WL = Wireline logger measured depth
ft MSL = Elevation in feet relative to mean sea level
KB = Kelly Bushing
NAD 83 = North American Datum of 1983

1. ***Provide data on surface, intermediate, and long string casing and tubing. Data must include material, size, weight, grade and depth set.***

Table II-2: Casing/Tubing Details for I/W Well

Specifications	Casing / Tubing			
	Surface	Long-String	Liner	Tubing
Material	Steel	Steel	Steel	Steel
Size (in OD)	13-3/8"	9-5/8"	5-1/2"	5-1/2"
Weight (lb/ft)	54.5#	40#	17#	17#
Grade	K-55	J-55 & N-80	N-80	J-55
Depth Interval (ft)	0 - 630'	0 - 4716'	4687' - 4814'	0 - 4614'

Specifications	Casing / Tubing			
	Surface	Long-String	Liner	Tubing
Material	Steel	Steel	Steel	Steel
Size (in OD)	13-3/8"	9-5/8"	5-1/2"	5-1/2"
Weight (lb/ft)	54.5#	40#	17#	17#
Grade	J-55	J-55 & N-80	N-80	J-55
Depth Interval (ft)	0 - 630'	0 - 4716'	4687' - 4814'	0 - 4614'

Definitions
in OD = Outside diameter in inches
lb/ft = pounds per foot

2. ***Provide data on the well cement, such as type/class, additives, amount, and method of emplacement.***

Table II-3: Cement Details for I/W Well

Casing Size (in OD):	13-3/8"	9-5/8"
Cement Details		
Type/Class	G	G
Additives	Woodland mix cement[1]	5% NaCl, 1.25% Halad-322, 0.5% Halad-344, 0.25lb/sk Pheno Seal, 0.5% D-Air, 0.2% SuperCBL,
Amount	500 sacks (800 ft^3)	1975 ft^3
Method of Emplacement	Pumped	Pumped

Definitions
in OD = Outside diameter in inches
Footnotes
1 Halliburton proprietary formula

3. ***Provide data on the packer (if used) such as type, name and model, setting depth, and type of annular fluid used*.**

Table II-4: Packer Details for I/W Well

Type	Permanent
Name/Model	Baker Model SC-1
Setting Depth (ft MD)	4614'
Type of Annular Fluid	4% KCL with biocide and corrosion inhibitor

Definitions
ft MD= Measured depth below Kelly Bushing in feet
KCL = Potassium Chloride

4. ***Provide data on centralizers to include number, type and depth*.**

Table II-5: Centralizer Details for I/W Well

Casing Size (in OD):	**13-3/8"**	**9-5/8"**	
Number	3	20	83
Type	Single bow	double bow spring	single bow spring
Depth (ft MD)	615' to 550'	4690' - 3890'	3850' - 570'

Definitions
ft MD= Measured depth below Kelly Bushing in feet
in OD = Outside diameter in inches

5. *Provide data on bottom hole completions.*

Table II-6: Bottom Hole Completion Details for I/W Well

in OD of Pipe	in ID of Pipe	Length of Pipe (feet)	To Depth (ft MD)	Description
5-1/2"	4.767"	4614'	4614'	5-1/2", 17#, J-55
8.6"	6"	4.56'	4618.56'	Baker SC-1 Packer
7.63"	6.969"	5.99'	4624.55'	7-5/8", 26#, Upper Extension
8.13"	6"	2.12'	4626.67'	Baker Model S Sliding Sleeve
7.63"	6"	1.7'	4628.37'	Baker Seal Bore
7"	6.366"	19.63'	4648'	Lower Extension
5.5"	4.892"	38.30'	4686.3'	Blank 5-1/2", 17#, N-80
6"	4.892"	122.68'	4808.98'	5-1/2" wire wrapped screen
5.5"	3.5"	2.63'	4811.61'	O-ring seal sub
5.5"	N/A	1.9'	4813.51'	shoe

Definitions
ft MD = Measured depth below Kelly Bushing in feet
in OD = Outside diameter in inches
in ID = Inside diameter in inches
= lb/ft

6. *Provide data on well stimulation used.*

~~*Data on well stimulation will be provided following I/W Well stimulation scheduled for November 24 or 25, 2014.*~~A stimulation program was implemented on November 26, 2014 to help increase the formation permeability near the well. Acidizing was performed in three stages using coiled tubing placed in the open hole injection zone interval from 4,616' to 4,813' MD, while reciprocating a Roto Jet nozzle from 4,813' to 4,687' MD. During each stage, pressure was monitored at bottom hole using the Side Pocket Surface Readout (SPSRO) permanent downhole pressure gauge (see **Table IV-4** for instrument details) and at the surface at the 5-1/2" tubing head. The well was shut in for one hour between Stages 1 and 2 and for one hour between Stages 2 and 3. Details of each stage are provided below:

Stage 1: Pumped 500 gallons of 15% hydrochloric acid (HCL) (One Shot Acid) at 0.5 barrels per minute (BPM). At the end of pumping, bottom hole pressure was 2,300 pounds per square inch gage (psig) and surface tubing head pressure was 480 psig.

Stage 2: Pumped 1,000 gallons of 15% HCl and 1,000 gallons of 12% HCL/3% hydrofluoric (HF) acid at 2.2 BPM. At the end of pumping, bottom hole pressure was 2,070 psig and surface tubing head pressure was 520 psig.

Stage 3: Pumped 2,000 gallons of 12% HCL/3% HF acid and 1,500 gallons of 7.5% HCl acid at 2.5 BPM. Acid was displaced with 3,000 gallons of 5% ammonium chloride (NH_4CL). At the end of pumping, bottom hole pressure was 1,849 psig and surface tubing head pressure was 322 psig.

III. Description of Surface Equipment

1. *Provide data and a sketch of holding tanks, flow lines, filters and injection pump.*

The Temporary Site Facility (TSF) equipment will be deployed on a gravel pad that measures 750' x 272' (approximately 4.7 acres). TSF major equipment are listed the table below and their layout on the pad are depicted in: TSF General Arrangement (Stantec Drawing M00-01-001; **Appendix III-1**).

Table III-1: Temporary Site Facility (TSF) Surface Equipment

TSF Equipment Description	Equipment Identifier (Appendix III-1)
7 Trailers	1 - 7
5kV switchgear	8
10 MVA Main Transformer	9
Low Pressure (LP) Compressor No. 1	10
LP Compressor No. 2	11
15 kV Breaker	12
Control Building	13
Frac Tank No.1 (500 barrel)	14
Frac Tank No. 2 (500 barrel)	15
2.5 MVA Station Service Transformer No. 1	16
2.5 MVA Station Service Transformer No. 2	17
15 KV Switch	18
480 V Switchgear No. 1	19
480 V Switchgear No. 2	20
Nitrogen Production Unit (NPU) No. 1	21
NPU No. 2	22
NPU No. 3	23
NPU No. 4	24
High Pressure (HP) Compressor No. 1	25
HP Compressor No. 2	26
HP Compressor No. 3	27
HP Compressor No. 4	28
HP Compressor No. 5	29
Neutral Grounding Resistor	30
480 V Switchboard	31
Trailer Power Distribution	32
27 kV Recloser	33
Test Separator	34
Reducing Station	35
Analyzer Station	36
Metering	37

Each low pressure (LP) compressor can produce a maximum flow of 10,432 scfm at 355 pounds per square inch gage (psig) and are driven by a 4,000 hp electric motor. The Piping and Instrumentation Diagram (P&ID) for the LP compressors is Cooper Compression drawing FF7065-14218 (**Appendix III-3**).

The output of the LP Compressors passes through a 1.0 micron coalescer filter, followed by a 0.01 micron coalescer filter. The locations and the specifications of the filters are provided on the P&ID for the Membrane Nitrogen Production Unit (NPU) (GENERON drawing MM085010_D-0101; **Appendix III-5**). The compressed air from the LP compressors delivered to the NPU has the O_2 removed and 95% Nitrogen is produced.

The output of the NPUs is delivered to the high pressure (HP) booster compressors. Each HP compressor unit is an Ariel JGA-4 four-stage reciprocating compressor capable of a maximum flow of 2,000 standard cubic feet per minute (scfm) and driven by a 600 horsepower (hp) electric motor. The P&ID for the HP booster compression skid is GENERON drawing BNC141001A_D-0101 (**Appendix III-2**). The output of the HP compressors is delivered to the I/W well.

Tanks for formation water produced with the withdrawal gas stream include a test separator and two 500 barrel (21,000 gallon) frac tanks. The TSF P&ID showing the separator and frac tanks is Stantec drawing P00-02-002-0 (**Appendix III-4**).

IV. Monitoring Systems

1. *Provide data on recording and non-recording injection pressure gauges, casing-tubing annulus pressure gauges, injection rate meters, temperature meters, and other meters or gauges.*

Specifications for sensors and other instruments to be used for technical data acquisition are summarized below in **Table IV-1**. The instrument locations, identified by their Tag Numbers, are shown in the P&ID diagrams referenced in the right-most column (**Appendices IV-1, IV-2 and IV-3).**

Table IV-1: Specifications for Gauges, Meters and Sensors

Location	Equipment	Instrument Type	Manufacturer / Model	Accuracy	Operating Limits[1]	Stability	Calibration Frequency	Redundancy	Diagram No. (Instrument located by Tag No.)
I/W Well Downhole (with surface read-out)	Downhole Press/Temp Sensors	Piezoresistive Pressure Transducer	Tendeka SPSRO P/T Quartz Tag No. 00-PT-015	0.02% full scale	500-10,000 psi	<0.02% full scale per year	Factory Calibration; mid-test calibration[2]; periodic check against wellhead sensors	None	--
		Platinum Wire RTD	Tendeka SPSRO P/T Quartz Tag No. 00-TT-015	± 045°F	77-350°F	--			
Piacentine 1-27 and Citizen Green 1 Downhole[4]	Suspended Press/Temp Sensors	Hybrid quartz crystal sensor	Metrolog CGM5	± 0.02%	0-15,000 up to 0-30,000 psi	--	Pre-test calibration; mid-test calibration check[2]	Redundant PT sensors on gauge	--
				± 0.3°F	0-302 °F	--			
I/W Well Wellhead	Press Sensor at tubing head and annulus	Absolute Pressure	Rosemount 3051S2CA4A2A11A1AE5Q4 Tag No. 00-PIT-012 (tubing head) Tag No. 00-PIT-018 (annulus)	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months	Factory Calibration; mid-test calibration check[2]	Additional to downhole sensor	P00-02-001-0 (Appendix IV-1)
	Temp element and transmitter at tubing head	Thermocouple	Pyromation R1T185L483-(TW)-SL-8HN31 Tag No. 00-TE-002 Rosemount 3144PD1A1E5M5Q4 Tag No. 00-TIT-002	± 0.02% of span	0-120°F (transmitter)	± 0.1% of reading for 24 months			
	Temp element and transmitter at annulus	Thermocouple	Omega SA1-RTD-4W-120 Tag. No. TE-018 Rosemount 648DX1D1I5WASWK1M5Q4F 6B5 Tag No. TIT-018	± 0.06%	-100-500°F (element) 0-120°F (transmitter)	<0.2% per year			
Piacentine 1-27 Wellhead	Press Sensors at tubing head and annulus	Absolute Pressure	Rosemount 3051S2CA4A2A11X5AWA3W K1I5M5Q4, 701PBKKF Tag No. 00-PIT-016A, 016B	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months	Factory Calibration; mid-test calibration check[2]	Additional to downhole sensor	P00-02-002-0 (Appendix IV-2)
	Temp element and transmitter at tubing head	Thermocouple	Omega SA1-RTD-4W-120 Tag. No. TE-016A Rosemount 648DX1D1I5WASWK1M5Q4F 6B5 Tag No. TIT-016A	± 0.06%	-100-500°F (element) 0-120°F (transmitter)	<0.2% per year			
	Temp element and transmitter at annulus	Thermocouple	Omega SA1-RTD-4W-120 Tag. No. TE-016B Rosemount 648DX1D1I5WASWK1M5Q4F 6B5	± 0.06%	-100-500°F (element) 0-120°F (transmitter)	<0.2% per year			

Location	Equipment	Instrument Type	Manufacturer / Model	Accuracy	Operating Limits[1]	Stability	Calibration Frequency	Redundancy	Diagram No. (Instrument located by Tag No.)
			Tag No. TIT-016B						
Citizen Green 1 Wellhead	Press Sensor at tubing head	Pressure	Barton Model 202A-2000	0.5% full scale	0 – 2000 psi	--	Vendor calibration at installation	None	--
Injection Pipe near I/W Well Manifold	Injection Gas Press/Temp /Flow	Differential Pressure Flow	Rosemount 3051S2CD2A2A11A1AE5Q4 Tag No. 01-FIT-004	± 0.03% of span	0-100 inches water column	± 0.15% of reading for 24 months	Factory calibration of press/temp sensors; vendor calibration of flow meter package; mid-test calibration check[2,3]	None. Separate flow meters for injection and flow.	P00-02-001-0 (Appendix IV-1)
		Absolute Pressure	Rosemount 3051S2CA4A2A11A1AE5Q4 Tag No. 01-PIT-004	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months			
		Thermocouple	Pyromation R1T185L483-(TW)-SL-8HN31 Tag No. 01-TE-004 Rosemount 3144PD1A1EM5Q45 Tag No. 01-TIT-004	± 0.02% of span	0-120°F (transmitter)	± 0.1% of reading for 24 months			
Flow Pipe near Test Separator	Gas to Atmosphere Press/Temp /Flow	Differential Pressure Flow	Rosemount 3051S2CD2A2A11A1AE5Q4 Tag No. 02-FIT-009	± 0.03% of span	0-100 inches water column	± 0.15% of reading for 24 months			P00-02-002-0 (Appendix IV-2)
		Absolute Pressure	Rosemount 3051S2CA2A2A11A1AE5Q4 Tag No. 02-PIT-009	± 0.03% of span	0-3,000 psi	± 0.15% of reading for 24 months			
		Thermocouple	Rosemount 0068N21C30A060W44E5XA Tag No. 01-TE-009 Rosemount 3144PD1A1E5M5Q4XA Tag No. 02-TIT-009	± 0.02% of span	0-120°F (transmitter)	± 0.1% of reading for 24 months			
I/W Well Manifold near Wellhead	Hydrocarbon Analyzer 1	Flame Ionization Detector (FID) on slip stream	Baseline Modcon Series 9000 THA Tag No. DAS-AIT-010A	± 1% full scale	1-20,000 ppm	± 1% for 24 hours	At installation; daily automatic calibration with internal methane standard	2x Redundancy	P00-02-002-0 (Appendix IV-2)
	Hydrocarbon Analyzer 2	IR Detector on slip stream	Hitech Inst. IR600 series Tag No. DAS-AIT-010B	±2.5%	0-100% Methane	±2 %	At installation; daily check against Hydrocarbon Analyzer 1		
	Oxygen Sensor	Zirconia sensor	Sensotec Rapidox 2100ZF Tag No. DAS-AIT-011A, 011B	± 1%	<1 ppm to 100% O_2 10E-4 Torr to 40 Bar 5 to 35°C	± 2% per month	At installation; weekly check using ambient air	2x Redundancy	P00-02-002-0 (Appendix IV-2)
	Fire and Flame Sensor	IR/UV Sensor	Honeywell FS20X	NA	-40 to +185°F	--	At installation	None	Minimax Device Layout (Appendix IV-3)

Location	Equipment	Instrument Type	Manufacturer / Model	Accuracy	Operating Limits[1]	Stability	Calibration Frequency	Redundancy	Diagram No. (Instrument located by Tag No.)
Water Tank	Analog Level Transmitter	Piezoresistive pressure sensor	Magtech LT-1	½ to ¼ inch resolution	-400 to 400" H_2O Maximum operating pressure 4,500 psi		At installation; weekly visual check	None	--

Footnotes:

1. All pressure gauges will have a full pressure range of at least 50% greater than the anticipated operating pressure.
2. Mid-test field calibration would be performed by a mobile calibration service at the end of the bubble building period. Additional field calibration is not anticipated to be needed, but may be performed if significant instrument drift is detected during mid-test calibration checks.
3. Additional mid-test verification of flow would be performed using a portable strap-on ultrasonic flow meter.
4. Downhole pressure/temperature sensor for two observation wells deployed periodically by slickline; in the case of the Citizen Green 1, only once just prior to initial depleted air injection.

Definitions

" = inches
°F = degrees Fahrenheit
°C = degrees Celsius
H_2O = water
RTD = Resistance Temperature Detector
FID = Flame Ionization Detector
IR = Infrared
P&ID = Piping and instrumentation diagram
ppm = parts per million
psi = pounds per square inch
-- = Not Applicable

2. ***Provide data on constructed monitoring wells such as location, depth, casing diameter, method of cementing, etc.***

"As-build" construction details for the observation wells (Piacentine 1-27 and Piacentine 2-27) are provided in the series of tables below. As-built schematics for the two observation wells are provided in **Appendix IV-4**. The locations of the observation wells are shown in **Appendix II-2**.

Table IV-2: General Details for Observation Wells

	Piacentine #1-27	Piacentine #2-27
API No.	7720484	7720736
Surface Location Coordinates (Lat-Long)	38.082389999 121.421970000 (NAD 83)	38.081855418 121.422162206 (NAD 83)
Original Well - Rig Release Date	25-Jul-86	28-Mar-13
Most Recent Re-work/Re-drill Program - Rig Release Date	6-Oct-14	NA
Surface Elevation (ft MSL)	-6'	-6'
KB Elevation (ft MSL)	7'	6'
Total Drilled Depth (ft MD)	4900'	4970'
Completed (Present) Well Depth (ft MD)	4715'	4920'
Perforation Depth Interval (ft MD)	4670' - 4682'	None

Definitions
ft MD = Measured depth below Kelly Bushing in feet
ft MSL = Elevation in feet relative to mean sea level
KB = Kelly Bushing
NA = Not applicable
NAD 83 = North American Datum of 1983

Table IV-3a: Casing/Tubing Details for Piacentine 1-27 Observation Well

Specifications	Casing / Tubing		
	Surface	**Long-String**	**Tubing**
Material	Steel	Steel	Steel
Size (in OD)	8-5/8"	5-1/2"	2-3/8"
Weight (lb/ft)	24#	15.5#	4.7#
Grade	K-55	K-55	J-55
Depth Interval (ft MD)	0 - 627'	0 - 4900'	0 - 4587'

Definitions
ft MD= Measured depth below Kelly Bushing in feet
in OD = Outside diameter in inches
lb/ft = pounds per foot

Table IV-3b: Casing/Tubing Details for Piacentine 2-27 Observation Well

Specifications	Casing / Tubing	
	Surface	**Long-String**
Material	Steel	Steel
Size (in OD)	9-5/8"	5-1/2"
Weight (lb/ft)	36#	15.5#
Grade	J-55	J-55
Depth Interval (ft MD)	0 - 614'	0 - 4967'

Definitions
ft MD= Measured depth below Kelly Bushing in feet
in OD = Outside diameter in inches
lb/ft = pounds per foot

Table IV-4: Cement Details for Observation Wells

Well Name:	**Piacentine #1-27**		**Piacentine #2-27**	
Casing Size (in OD):	**8-5/8"**	**5-1/2"**	**9-5/8"**	**5-1/2"**
Cement Details				
Type/Class	G	G	G	G
Additives	8% gel, 3% $CaCl_2$	10% salt, 0.75% CD-31, 0.2% FP-8	VERSACEM lead cement premixed with 2% $CaCl_2$ and 0.2% Versaset; ECONOCEM tail cement premixed 5% Salt-Interpid-Moab Fine	50/50 Poz/Premium Plus lead cement with 3% KCl, 0.75% Halad-322, 0.2% Halad-344 and 0.5% D-Air 3000; Tail cement with 2% $CaCl_2$, 0.75% Halad-322, 0.2% Halad-344 and 0.15% SuperCBL
Amount	260 sacks (461 ft^3)	150 sacks (174 ft^3)	220 sacks (348 ft^3)	1180 sacks (1397 ft^3)
Method of Emplacement	Pumped	Pumped	Pumped	Pumped

Definitions
in OD = Outside diameter in inches
$CaCL_2$ = Calcium Chloride
KCl = Potassium Chloride

Table IV-5: Packer Details for Observation Wells

Packer Details	Piacentine #1-27	Piacentine #2-27
Type	Retrievable Production	None
Name/Model	45A4 R-3	
Setting Depth (ft MD)	4611'	
Type of Annular Fluid	4% KCL with biocide and corrosion inhibitor	

Definitions
ft MD= Measured depth below Kelly Bushing in feet
KCL = Potassium Chloride

Table IV-6: Centralizer Details for Observation Wells

Surface Casing		
Centralizer Details	Piacentine #1-27	Piacentine #2-27
Number	4	1
Type	Single Bow	Single Bow
Depth (ft MD)	617' - 497'	599'

Production Casing		
Centralizer Details	Piacentine #1-27	Piacentine #2-27
Number	6	9
Type	Single Bow	Single Bow
Depth (ft MD)	4885' to 4648'	4890' to 4530'

Definitions
ft MD = Measured depth below Kelly Bushing in feet

V. Logging and Testing Results

1. ***Provide a descriptive report interpreting the results of geophysical logs and other tests. Include a description and data on deviation checks run during drilling.***

Borehole Logging and Coring Program Results

The borehole logging and coring program for the I/W Well is outlined below in Table V-1. The program consisted of mud logging (Geolog), open-hole and cased-hole geophysical logging (Halliburton), discrete-depth formation pressure measurements and pressure transient analysis (Halliburton) and sidewall coring (Halliburton). The mud log, geophysical logs, formation pressure data and sidewall core analyses results are provided in **Appendices V-1, V-2, V-3** and **V-4**, respectively.

Table V-1: Logging / Sidewall Coring Program for I/W Well

Logging / Coring Program		Halliburton Tool	Primary Purpose	Depth Range (ft MD)
Open-hole	Mud Log	N/A (Geolog)	lithology, rate of penetration, gas shows	70' - 4938'
	Spontaneous Potential (SP) log	Spontaneous Potential (SP)	Sand layer definition, formation water salinity	
	Dual induction log (DIL)	Array Compensated True Resistivity (ACRt)	Formation water salinity, hydrocarbon indicator, water/hydrocarbon saturation (with porosity measurements)	
	Micro-resistivity Tool (MRT)	Micro Log (ML)	Flushed and invaded zone resistivity, permeability indicator	
	Gamma Ray (GR) log	Gamma Ray (GR)	Shale indicator	
	Formation Density Compensated (FDC) log	Spectral Density Log (SDL)	Porosity measurement, water/hydrocarbon saturation (with resistivity measurements)	
	Compensated Neutron Log (CNL)	Dual Spaced Neutron Log (DSN)	Porosity measurement, water/hydrocarbon saturation (with resistivity measurements)	
	Caliper log (CAL)	ICT Multi-arm Caliper	Show variations in borehole size and geometry	
	Sonic log (SL)	Wave Sonic Semblance (dipole) Tool (WSST)	Formation velocity, synthetic seismograms. Can be used for porosity determination.	620' - 4898'
	Repeat Formation Tester (RFT)	Reservoir Description Tool (RDT)	Depth-discrete pressure measurement, permeability determination	4610' - 4915'
	Sidewall coring (SWC)	Percussion Sidewall Coring Tool	Reservoir and confining zone parameters. Compare results to those from Piacentine 2-27 conventional core.	4645' - 4903'
Cased-hole	Cement bond log (CBD)	Radial cement bond log (RCBL) NL/GR	Evaluate integrity of annular cement seal and identify channels that might allow fluids to migrate between formations	12' - 4692'

Definitions
ft MD = measured depth in feet below kelly bushing

Analysis and interpretation of the I/W Well geophysical logs was performed by Digital Formation, a petrophysical consulting company located in Denver, Colorado. The Digital Formation report, which includes analytical methodologies, formulas and rock property results, as well as composite interpretation logs, is provided in **Appendix V-5**.

Physical, textural, mineralogical and hydraulic properties of the target injection zone (MRF reservoir) and overlying confining zone (Capay Shale) were determined through petrophysical analysis of I/W Well sidewall core plugs performed by CoreLab in their Bakersfield, California facility. The routine core analyses performed by Corelab are listed and described below in **Table V-2**.

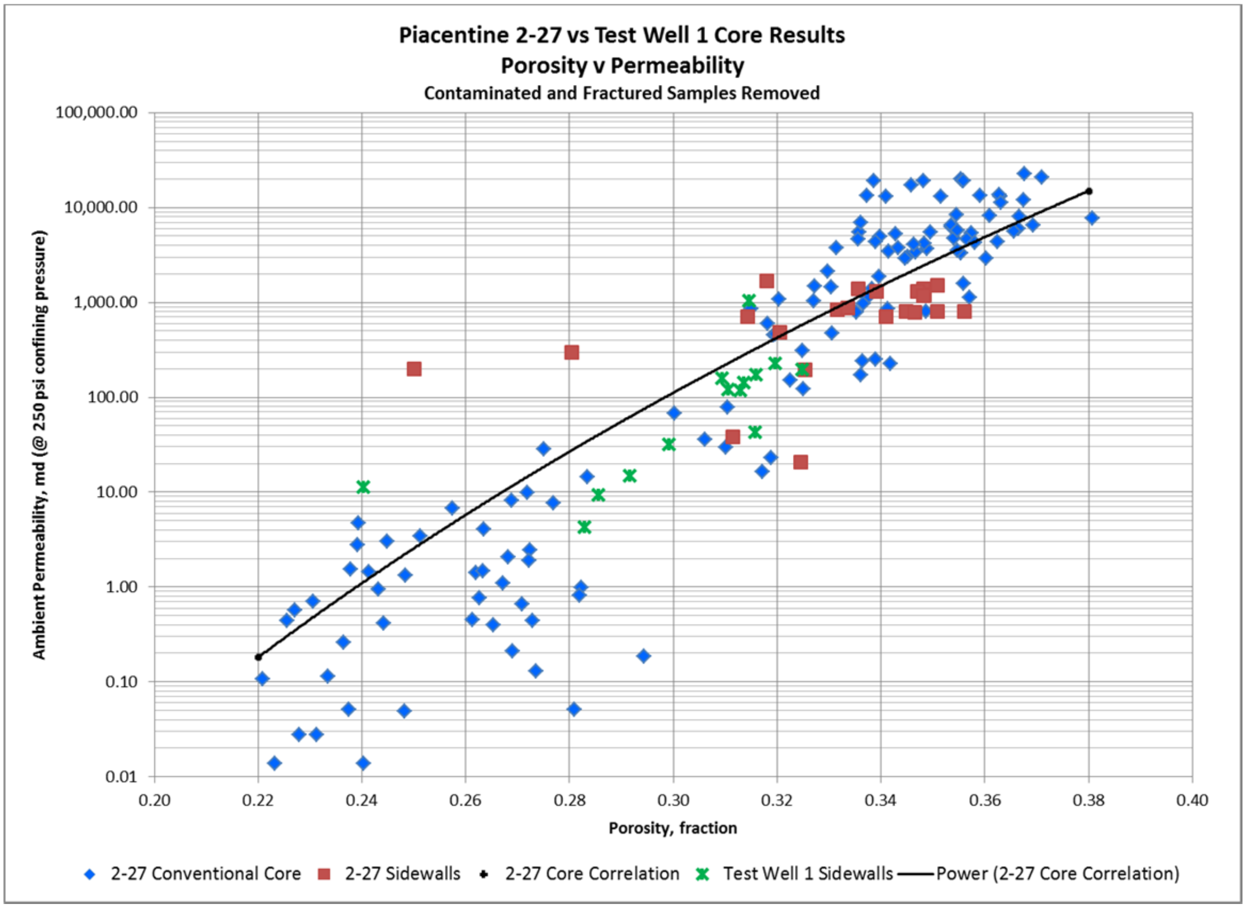
Table V-2: Routine Sidewall Core Analyses

Core Analyses	Description
Porosity	Total pore space in sample as a percentage of total sample volume. Used in all reservoir volumetric calculations.
Grain density	Density of reservoir solids whose value determined by rock mineralogy. Input to formula relating sample porosity and bulk density.
Horizontal permeability to air	Intrinsic characteristic of rock that determines how easily air can pass through it. Measured parallel to rock layering, which is preferential flow direction in reservoir. High horizontal permeability is an indicator of good reservoir quality.
Fluid saturation	Percentage of rock porosity occupied by water. Affects the relative permeability of reservoir with respect to air, with permeability to air decreasing as fluid saturation increases.
V-clay	Ratio of clay (or shale) volume to total rock matrix volume; expressed as a decimal. High V-clay usually indicates low reservoir. Used as correction factor in log porosity calculations.

The average porosity of the injection zone based on sidewall core analyses results is provided in **Section I**, **Table I-2**. A brief summary of the results of core and log analysis for the MRF reservoir injection zone and the Capay Shale confining unit is provided below.

I/W well sidewall core samples were collected in the Domengine (1 sample), Capay (4 samples), MRF reservoir (12 recovered samples), sub-reservoir shale (2 samples) and MR-2 (1 sample). I/W well sidewall core porosity and horizontal permeability (to air) measurements (fractured sample measurements removed) were cross-plotted, along with sidewall core and conventional core porosity and permeability measurements from approximately the same stratigraphic intervals in the Piacentine 2-27 (**Figure V-1**). The Piacentine 2-27 had several samples that plotted farther to the upper-right and the lower-left in Figure V-1 compared to the I/W Well samples (green crosses), indicating the presence of both higher and lower porosity/permeability sand layers in the Piacentine 2-27, but all sample results from both wells plotted along the same trend.

Figure V-1: Cross-plot of Core Porosity and Permeability Measurements from Piacentine 2-27 and I/W Well



Permeabilities of I/W Well sidewall core samples from the MRF reservoir interval that was subsequently under-reamed (to 17" diameter) and gravel packed (4722' to 4815' MD); corresponding to the compression test injection zone) range from 9.2 to 225.4 mD (**Appendix V-4**), with an arithmetic average permeability of 115 mD and a geometric mean permeability of 72 mD (**Table V-3**). Porosity in the injection interval ranges from 28.6% to 32.0%. There is very good agreement between the I/W Well sidewall core porosities and the porosity log curve on the Digital Formation composite logs (**Appendix V-5**). This confirmation of I/W Well core porosities supports the validity of I/W Well permeabilities because they fall along the same porosity/permeability cross-plot trend as the Piacentine 2-27 samples (**Figure V-1**). The generally lower permeability of the MRF in the I/W Well compared to the Piacentine 2-27 is believed to represent sedimentological heterogeneity in the formation (i.e. lateral facies change), with average porosity and permeability increasing away from the I/W Well towards the Piacentine 1-27 and Piacentine 2-27.

Table V-3: I/W Well Sidewall Core Porosity and Permeability in Mokelumne River Formation

Ft-MD	Permeability (mD) MRF Reservoir		MRF Reservoir (low & high outliers removed)		MRF Injection Zone (4722' - 4815')		Porosity (%) MRF Injection Zone (4722' - 4815')	
4713	11.2		11.2		-		-	
4754	9.2		-		9.2		28.6	
4765	141.5		141.5		141.5		31.4	
4771	42.1		42.1		42.1		31.6	
4794	225.4		225.4		225.4		32.0	
4810	159.1		159.1		159.1		30.9	
4817	118.2		118.2		-		-	
4821	31.5		31.5		-		-	
4830	119.0		119.0		-		-	
4840	194.6		194.6		-		-	
4846	1029.3		-		-		-	
	Arithmetic Average	Geometric Mean	Arithmetic Average	Geometric Mean	Arithmetic Average	Geometric Mean	Arithmetic Average	Geometric Mean
	189	86	116	84	115	72	31	31

Definitions
Hyphen (-) where value not presented because not applicable to interval of interest or is removed outlier
ft MD = Measured depth from kelly bushing
mD = milli-Darcy
MRF = Mokelumne River Formation
' = Foot
% = Percent

Horizontal permeabilities measured in the four Capay Shale sidewall cores samples (4665’ to 4698’ MD) ranged from 102.7 to 305.9 mD. These permeabilities are much higher than those measured in Capay Shale core plugs sub-sampled from the Piacentine 2-27 conventional core, which showed a harmonic mean of 17 horizontal permeabilities (at ambient stress) of 0.27 mD and a harmonic mean of 4 vertical permeabilities (at confining stress) of 0.04 mD (PG&E, 2014; Table G-6). The Corelab report (**Appendix V-4**) shows that visible fractures were present in all four of the Capay sidewall cores in the I/W Well, probably produced by the percussion sidewall coring technique, which explains the anomalously high permeability measurements. Note that the sidewall core samples from the comparatively more silty-sandy sub-reservoir shale interval (samples at 4857’ and 4870’), which are not fractured, have permeabilities of 4.2 and 14.7 mD, approximately one order of magnitude lower than for the four Capay Shale samples. In the absence of induced fractures, it would be expected that the Capay Shale would have lower permeability that the sub-reservoir shale. Rock physics modeling performed by Digital Formation (**Appendix V-5**) using the dipole sonic log and based on a cross-plot relationship between Young’s Modulus and Poisson’s ratio indicates that the Capay Shale is ductile, which is a favorable characteristic for a seal rock.

Pressure Measurements and Pressure Transient Analysis

When the I/W Well was drilled, reservoir pressure measurements were taken in the Domengine Formation and the MRF injection zone using Halliburton's Reservoir Description Tool (RDT™). This tool allows multiple in-situ pressure measurements to be made at various depths using a special probe. The measured pressures are shown in **Table V-4**. The RDT pressures for the MRF (including the MR2 sand below the MRF injection zone) ranged from 1891.7 pounds per square inch, atmospheric (psia) to 1974.2 psia. The average pressure gradient in the Domengine Formation is 0.4374 pounds per square inch per foot (psi/ft) and in the MRF injection zone (4671' – 4759' TVD) is 0.4057 psi/ft (after elimination of one pressure outlier at 4,702.7 feet). The average pressure gradient in the underlying MR2 is 0.4067 psi/ft, just slightly higher than in the MRF injection zone, indicating that the MR2 is in pressure communication with the MRF injection zone.

Table V-4: Depth-Discrete Pressure Measurements from I/W Well

Formation Zone	Depth[1]	Original Pressure (psi)[2]	Pressure Test Data (psi)[3]	Pressure Gradient at time of RDT (psi/feet)	Pressure Deviation from Hydrostatic Gradient (psi)[4]
Domengine Sand	4564.73		1997.1	0.4375	20.6
	4602.5		2013	0.4374	20.1
MRF Reservoir Zone	4663.83	2080 (0.438 psi/ft)	1891.7	0.4056	-127.7
	4672.56		1894.6	0.4055	-128.6
	4678.02		1897.5	0.4056	-128.1
	4702.7		1949*	0.4144	-87.3
	4715.9		1914.2	0.4059	-127.8
	4740.5		1924.6	0.4060	-128.0
	4763.3		1934.4	0.4061	-128.1
	4778.5		1940.8	0.4062	-128.3
	4787.1		1944.6	0.4062	-128.2
MR2 Sand (Below Sub Reservoir Shale)	4843.3	--	1969.7	0.4067	-127.4
	4853.8		1974.2	0.4067	-127.5

Notes:

1 Depth in feet (TVD)

2 Discovery pressure in Moresco et al. Unit A 1 at 4744'-4760'

3 Pressure measurements taken using Halliburton Reservoir Description Tool (RDT™) on October 18, 2014.

4 Hydrostatic gradient is calculated as 0.433 psi/ft assuming the density of fresh water. Actual gradient in saline formations will be slightly higher.

psi = pounds per square inch

TVD = True Vertical Depth from kelly bushing

* Outlier pressure measurement

The pressure data indicate that the MRF injection zone and the underlying MR2 sand are pressure depleted relative to normal hydrostatic by -127 to -128 psia due to historical natural gas production in the King Island MRF gas reservoir, and that the sub-reservoir shale separating the MRF injection zone and MR2 allows some pressure communication. The normal hydrostatic gradient in the basal sands of the Domengine Formation provides further proof that the Capay Shale is an effective top seal for the MRF injection zone.

Step Rate Test (SRT) and Fall Off Test (FOT) Results

On October 27, 2014, a Step Rate Test (SRT) and Fall-Off Test (FOT) were conducted on the I/W Well by Irani Engineering and MHA Petroleum Consultants (MHA) in accordance with the procedures outlined in: *Plan to Conduct Step-Rate Test (SRT) and Initial Fall-Off Test (FOT)*, prepared by MHA and dated September 25, 2014 (plan provided in **Appendix V-6a**). The SRT/FOT Plan was approved by EPA on October 9, 2014.

A report was prepared by MHA that provides: 1) general information, 2) an overview of the SRT and FOT, 3) an analysis of the injection pressure-rate data and estimated fracture pressure obtained during the SRT, and 4) analysis of the FOT pressure data including determination of the formation transmissivity, radius of investigation, and skin factor (wellbore damage). The MHA report is provided in **Appendix V-6b** and the test results are summarized below.

The pre-SRT activities included several attempts to establish water injection into the MRF without success and as a result, the well had to be deepened twice to increase the test interval beyond the original 10 feet proposed in the testing plan. The MRF reservoir interval tested was 4722' to 4780' MD. The tested interval gross thickness was 58' measured thickness (MT) (55' true vertical thickness [TVT]) and the net sand thickness was 34' MT (31' TVT) (Digital Formation Petrophysical Report, **Appendix V-5**). Pressures were collected both at the surface and bottomhole during the entire SRT/FOT procedure.

The SRT was performed using pump trucks and 4% potassium chloride (KCL) water. The total injection period was 5.38 hours and there were at least three injection rates greater than the formation breakdown pressure. After the SRT, the well was shut-in for 12 hours to record the pressure fall-off, representing the FOT. The formation breakdown pressure based on the slope change on the pressure vs injection rate plot was 3,940 psia (measured in bottomhole gauge set at 4,687' MD), corresponding to a fracture pressure gradient of 0.847 psi/ft. The instantaneous shut-in pressure (ISIP), representing the minimum pressure required to hold open a fracture, was determined to be 3,757.5 psi (bottomhole), corresponding to a fracture gradient of 0.808 psi/ft. There is good agreement between the two formation breakdown pressures.

The pressure transient data from the bottomhole pressure gauge was input into a commercial well test software program marketed and supported by IHS called *WellTest*. A summary of the *WellTest* FOT analyses results is provided in the table below:

Table V-5: FOT Results from I/W Well

Well / Test Date	PGE Test Well 1 / 27-28Oct2014
Test Type	Injection / Fall-off
Flow Capacity (kh)	4,340 mD-ft
Effective Thickness (h)	31 feet
Effective Permeability (k)	140 mD
Total Skin Factor (s')	0.59
Radius of Investigation (r_{inv})	379 feet
Reservoir (Formation) Compressibility (c)	3.3243e-06 1/psi

Definitions:
mD = milliDarcy
mD-ft = milliDarcy * feet

The permeability derived from the FOT data (140 mD) is within the range of sidewall core permeabilities for the injection zone (**Table V-3**). Though the FOT effective permeability is to water while the sidewall core permeabilities are to air, they are comparable because the tested zone around the I/W Well is 85% to 90% water saturation. There is no indication on a log-log diagnostic plot of linear flow (1/2 slope) associated with a fractured wellbore (refer to MHA FOT/SRT report in **Appendix V-6b)**. The induced fracture during the SRT must have closed immediately after the water injection ended since there was nothing to keep it open (such as proppant).

Directional Survey

The I/W Well was drilled vertically from surface to 3450' MD. The borehole was surveyed every 400' from the surface casing shoe to 3450' MD, and was found to have "walked" 6.8' west from plan. The borehole kicked-off at 3463' MD, built angle at 3° to 5.77° per 100' and attained a maximum inclination of 20° at 4132' MD that was held to total depth (TD) at 4963' MD (4950' MD wireline [WL]). The I/W Well reached TD at a surface projected location 305' north and 258' east of the surface location (40.18° azimuth). The figure showing well locations provided in **Appendix II-2** depicts an aerial view of the planned and actual directional wellbore paths using coordinates presented in the Halliburton directional program (pre-drill) and directional survey, both provided in **Appendix V-7**.

References

PG&E, 2014. Underground Injection Control Permit Application Technical Attachments, PG&E Compressed Air Energy Storage Project Compression Testing Program, King Island Gas Field, San Joaquin County, California. Revised April 18, 2014.

VI. As-Built Diagrammatic Sketch of Injection Well

1. ***Provide an as-built diagrammatic sketch of the injection well showing casing, cement, tubing, packer, etc., with proper sealing depths. This sketch should include well head and gauges.***

Schematics showing the as-built I/W Well and wellhead construction details ~~*will be prepared following I/W Well completion, scheduled for November 20-25, 2014*~~are provided in **Appendices VI-1a and VI-1b**.

VII. Data Demonstrating Mechanical Integrity of Injection and Monitoring Well

1. ***Provide data demonstrating mechanical integrity pursuant to 40 CFR 146.08.***

~~*Data*~~Pressure charts demonstrating mechanical integrity ~~*will be provided following the mechanical integrity tests (MITs), which will be performed on*~~of the I/W Well and the Piacentine 1-27 ~~*from*~~observation well are provided in **Appendices VII-1a and VII-1b**.

On November ~~*20-25*~~23, 2014~~.~~, the annulus between the 9-5/8" casing and 5-1/2" tubing in the I/W Well was pressured to 2,500 psig and held for one hour without any pressure drop, as demonstrated by the red line in the chart in **Appendix VII-1a**.

On November 23, 2014, the annulus between the 5-1/2" casing and 2-3/8" tubing in the Piacentine 1-27 was pressured to 2,500 psig and held for ½ hour without any pressure drop, as demonstrated by the red line in the chart in **Appendix VIII-1b**.

VIII. Compatibility of Injected Fluids with Injection and Confining Zones

1. ***Report on the compatibility of injected wastes with fluids and minerals in both the injection zone and the confining zone.***

Based on the detailed analyses described below, we have concluded that the planned injected media, comprising oxygen-depleted air (94% nitrogen) and ambient air (optional) have a low probability of causing impacts to the formation fluids and minerals that would negatively affect the reservoir, confining zone and well performance during the approximately 60 to 90 day compression test. This conclusion is based on an evaluation of potential chemical reactions and is supported by laboratory air chamber testing of an injection zone core sample that showed minor consumption of oxygen over the 5-day test period and pre-test and post-test scanning electron microscopy (SEM) and x-ray diffraction (XRD) analyses that showed no visible textural or mineralogical changes. As described below, the most likely potential reactions of concern between air and formation minerals identified in core samples involve oxidation of reduced iron-bearing minerals (especially pyrite and siderite) in the presence of oxygen.

Nature of Injected Media

The medium injected into the depleted gas reservoir at King Island will be air with its oxygen content depleted to a molar concentration of approximately 5%. This depleted air will consist of the following components:

- 94 mole % nitrogen;
- 5 mole % oxygen;
- 1 mole % argon; and
- Traces of carbon dioxide and other gases.

If a decision is made to conduct injection/withdrawal testing using ambient air, the chemical makeup of the injected fluid will be as follows:

- 78 mole % nitrogen;
- 21 mole % oxygen;
- 1 mole % argon; and
- Traces of carbon dioxide and other gases.

As described in the discussion that follows, the most likely reactions during both depleted air injection and optional ambient air injection are oxidation reactions of reduced mineral phases with oxygen and water. The amount of oxygen in depleted air is low (approximately 5%) and likely to represent a limiting factor for oxidation reactions during depleted air injection. Oxidation reactions are more likely to show a measurable impact during the optional ambient air injection. As the injection zone air bubble pore space will be mostly occupied by a gas phase (depleted air and minor natural gas in primary test; ambient air and minor natural gas in optional test), oxidation reactions may also be limited by the amount of water, especially in the mostly dehydrated zone expected to form immediately around the I/W Well.

Statement of Problem

Air injection and withdrawal in the injection zone could potentially cause chemical changes in formation water, and can lead to scaling or corrosion of well piping and formation plugging because of abiotic reactions between the injected air, formation water and formation solids.

Frequent and cyclical injection and withdrawal of air using CAES injection and withdrawal wells (I/W wells) in the mostly depleted King Island gas reservoir could cause chemical reactions, such as oxidation of pyrite [$FeS_2(s)$] by injected oxygen. Such reactions may increase corrosion because of acid production and increased salinity, and may also increase wellbore scaling and formation plugging because of the precipitation of reaction products such as iron oxyhydroxides. Changes in gas pressure and formation water temperatures can also lead to scale formation through dissolution and precipitation of carbonate, sulfate and silicate minerals.

Chemical Reactions

Issues associated with chemical reactions that may occur as the result of air injection and chemical reaction within porous formations include (Allen et al. 1983; Succar and Williams 2008):

- Oxidation of minerals such as pyrite in formation solids leading to production of secondary phases such as colloidal ferric hydroxide, which can result in permeability loss in the reservoir;
- Gypsum scale formation caused by pyrite oxidation and carbonate or silica scale caused by dissolution and re-precipitation in response to pressure and temperature changes during injection and withdrawal can lead to loss of formation permeability and equipment damage;
- Interaction of formation water with reaction products in the formation could accelerate the well tubing corrosion rate through increased salinity and acidity; and
- Particulates formed by mineral scale precipitation or corrosion or mineral particles released from the formation by dissolution of formation cement may be entrained in air flow, which may lead to equipment damage.

Mineral Oxidation and Dissolution Reactions

Reduced solid phases are present in the formation solids, including pyrite, siderite [$FeCO_3(s)$], iron-bearing clays and organic carbon. Reduced iron [ferrous iron, Fe^{2+}] present in the pyrite, siderite and clay is unstable in the presence of oxygen injected into the formation. For example, iron-bearing clay and pyrite in the formation at the Pittsfield, Illinois CAES test site were found to consume oxygen (USGS, 1990). Pyrite and siderite will oxidize to produce insoluble ferric [Fe^{3+}] oxyhydroxides and acidity:

$$FeS_2(s) + 3.75\ O_2 + 3.5\ H_2O \rightarrow Fe(OH)_3(s) + 2\ SO_4^{2-} + 4\ H^+ \qquad \text{Reaction (1)}$$

$$FeCO_3(s) + 0.25\ O_2 + 2.5\ H_2O \rightarrow Fe(OH)_3(s) + HCO_3^- + H^+ \qquad \text{Reaction (2)}$$

Acidity formed by pyrite or siderite oxidation could decrease the pH of formation water, causing potential well piping corrosion. However, acidity generated by pyrite or siderite oxidation is likely to be consumed by hydrolytic reaction of silicate minerals in the formation, such as reaction of potassium feldspar [$KAlSi_3O_8(s)$] to form the clay mineral kaolinite [$Al_4Si_4O_{10}(OH)_8(s)$] and quartz [$SiO_2(s)$]:

$$4\ KAlSi_3O_8(s) + 4\ H^+ + 2\ H_2O \rightarrow 4\ K^+ + Al_4Si_4O_{10}(OH)_8(s) + 8\ SiO_2(s) \qquad \text{Reaction (3)}$$

Hydrolytic reaction of other silicate minerals in the formation solids (**Table VIII-1**), including plagioclase and amphibole, is likely to form additional clay minerals such as illite and montmorillonite (Allen et al. 1983). These silicate mineral dissolution reactions are likely to maintain moderate pH values in the formation water and minimize corrosive acid formation. However, increased mineral volume associated with clay formation may reduce formation permeability.

Table VIII-1 Sidewall Core X-Ray Diffraction Data, Piacentine 2-27

	Bulk Mineralogy (Weight %)															Clay Mineralogy (Weight %)				
Depth (ft)	**Quartz**	**Opal A**	**Opal CT**	**Plagioclase**	**K-Feldspar**	**Calcite**	**Fe/Mg-Dolomite**	**Siderite**	**Amphibole**	**Apatite**	**Gypsum**	**Anhydrite**	**Halite**	**Pyrite**	**Total Clay**	**Kaolinite**	**Chlorite**	**Illite & Mica**	**MXL I/S[1]**	**% Smectite in MXL I/S[1]**
4721.5	49.5	0.0	0.0	13.5	9.9	0.0	0.0	0.0	1.8	0.0	0.0	0.0	0.0	0.0	25.5	15.1	3.7	2.3	4.4	50-60
4725.5	44.5	0.0	0.0	8.3	13.8	0.0	0.0	0.0	1.6	0.0	0.0	0.0	0.0	0.5	31.1	22.3	4.2	2.4	2.2	50-60
4733.5	38.8	0.0	0.0	6.9	9.9	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	0.0	41.9	27.3	3.7	2.6	8.3	50-60
4755.5	43.9	0.0	0.0	11.2	13.6	0.0	0.0	2.2	0.0	0.0	0.0	0.0	0.0	1.0	28.1	17.7	3.0	4.2	3.2	50-60
4757.5	52.3	0.0	0.0	11.1	12.2	0.0	0.0	0.0	1.4	0.0	0.0	0.0	0.0	0.7	22.3	14.3	2.1	3.7	2.2	50-60
4763.5	64.5	0.0	0.0	4.9	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	9.6	1.9	2.1	2.6	50-60
4765.5	56.3	0.0	0.0	4.2	9.3	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.0	29.2	16.3	4.6	6.6	1.7	50-60
4770.5	77.4	0.0	0.0	4.4	8.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	5.8	1.2	1.6	0.9	50-60
4775.5	74.7	0.0	0.0	6.5	10.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0	3.6	1.2	2.2	1.0	50-60
4778.5	54.2	0.0	0.0	3.8	10.5	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.8	16.7	8.7	1.7	1.7	4.6	50-60
4782.5	52.9	0.0	0.0	6.5	11.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.6	18.0	1.4	5.3	3.9	50-60
4785.5	53.4	0.0	0.0	7.5	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.1	16.7	1.5	4.9	2.0	50-60
4788.5	48.7	0.0	0.0	14.0	12.3	0.0	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	22.9	14.7	1.7	3.0	3.5	50-60
4792.2	66.1	0.0	0.0	9.1	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	13.8	7.8	1.5	2.4	2.1	50-60
4796.2[2]	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	96.2	0.0	0.0	0.0	0.0	0.0	50-60

Notes:

[1] MXL I/S = Mixed-layer illite-smectite

[2] Sample contains a significant amount of amorphous material, possibly organic

ft = feet

% = percent

Ferric oxyhydroxides produced by oxidation of reduced iron in pyrite, siderite or clays can form colloidal or larger-sized particles that could result in plugging of the formation, gravel pack or well screen. However, results from a single air chamber test with King Island Mokelumne River Formation (MRF) core material (summarized below), while not definitive, indicate that the rate of oxygen consumption will be relatively low, and the amount of iron oxyhydroxide formed will be limited by the reduced iron content of the formation minerals. Consequently, the likelihood of significant plugging from mineral oxidation reactions is fairly low.

Dissolution reactions caused by air injection could lead to particulates in withdrawn air if cementing minerals in the formation are dissolved and matrix particles are released. Fine-grained mineral reaction and corrosion products could also be released into withdrawn air, which could lead to equipment damage. Mobilization of particulates within the formation can also lead to permeability loss.

Scale Formation and Mineral Precipitation

Gypsum [$CaSO_4 \bullet 2H_2O(s)$] or barite [$BaSO_4(s)$] scale could form on well piping or well screens through reaction of sulfate [SO_4^{2-}] produced by pyrite oxidation (Reaction 1) with calcium or barium in the formation water. Gypsum or barite precipitation within the formation could also affect permeability. Silica solubility increases with increasing temperature. Because the formation temperature (123°F) is higher than surface temperatures, silica scale may form in the I/W well system in response to decreased temperatures as the entrained formation water is brought to the surface.

Calcite [$CaCO_3(s)$] scale could form on well piping or well screens and calcite precipitation may take place within the formation as a consequence of increased bicarbonate concentrations from siderite dissolution (Reaction 2). Carbonate scale deposition, including both calcite and siderite, could also be influenced by the effects of changing carbon dioxide (CO_2) partial pressures and temperature on solubility. The CO_2 partial pressure in the formation will be highest during air injection, and increasing CO_2 partial pressure increases carbonate mineral solubility. As entrained formation water is brought to the surface during air withdrawal, the CO_2 partial pressure will decrease and carbonate scale may form. However, the effect of decreasing CO_2 partial pressure is likely to be partially offset by lower surface temperatures, because carbonate mineral solubilities are inversely related to temperature.

Air Chamber Test on Injection Zone Core Sample

A pressurized core testing program was performed to investigate the potential interaction between injected air and reservoir materials at the depleted King Island gas field reservoir. The program involved a screening-level laboratory analysis of reservoir core material to evaluate the potential for oxygen-consuming chemical reactions that could occur when air is injected into the reservoir. The program was conducted by Core Laboratories on the 4,755.65 ft. core plug from the Piacentine 2-27 conventional core collected in the MRF reservoir sands. A summary of the test procedures and results is provided below.

The test involved collection and analysis of air samples taken from a pressurized chamber containing the core plug sample at various time intervals and pressures. X-ray diffraction (XRD) and scanning electron microscopy (SEM) analysis of the sample before the test identified minerals (pyrite, siderite and iron-bearing clays) and organic material with the potential to react with, and consume the oxygen in the air introduced into the air chamber (**Table VIII-2**).

Table VIII-2 Core Sample Mineralogy

Sample	-4755.5 ft MD, unreacted (pre-test)[1]	-4,755.65 ft MD, reacted (post-test)	Median[2]
Bulk Mineralogy, weight %			
Quartz	43.9	43.3	52.9
Plagioclase	11.2	10.4	6.9
K-feldspar	13.6	10.2	10.8
Siderite	2.2	1.0	0.0
Amphibole	0.0	0.0	0.0
Pyrite	1.0	1.0	0.0
Total clay	28.1	34.1	22.9
Clay Mineralogy, weight %			
Kaolinite	17.7	17.4	14.7
Chlorite	3.0	4.0	1.7
Illite & Mica	4.2	5.5	2.4
Mixed-layer illite-smectite	3.2[3]	7.2[3]	2.2[3]

Notes:

1 – Prior to the core test, XRD data were obtained from a -4,755.5 ft MD core sample; however, the -4,755.5 ft MD sample was compromised due to a power failure at the laboratory during testing, so the adjacent -4,755.65 ft MD sample (with similar visual appearance in core photographs) was used in the core test.

2 – Median of 15 percussion sidewall core XRD samples obtained prior to air chamber testing (Attachment G-1 of UIC Application [PG&E, 2014])

3 – Mixed-layer illite-smectite clay is 50 – 60 % smectite

% - percent

ft MD – measured depth in feet below Kelly Bushing

Air samples were collected from the chamber at the end of 3, 4 and 5 days at decreasing pressures of 2,100, 1,000 and 100 psi, respectively. The air samples were analyzed for helium, hydrogen, argon, oxygen, carbon dioxide, nitrogen, methane, ethane, and carbon isotopes ($\delta^{13}CO_2$ and $\delta^{13}CH_4$ – day-5 sample only) (**Table VIII-3**). XRD and SEM were performed on the post-test core plug sample to identify any possible mineralogical or textural changes produced by the test (**Table VIII-2**).

Table VIII-3 Gas Sample Analytical Results from Air Chamber Core Test

Sample Name	Description	Pressure (psi)	Duration (days)	He (%)	H_2 (%)	Ar (%)	O_2 (%)	CO_2 (%)	N_2 (%)	C_1 (%)	C_2 (%)	CO_2 $\delta^{13}C$ (‰)	CH_4 $\delta^{13}C$ (‰)
ACT1-1A	Laboratory-pure air cylinder	2,000	0	nd	nd	0.0214	21.58	nd	78.40	nd	nd	nm	nm
ACT1-1B	Laboratory-pure air cylinder	2,000	0	nd	nd	0.0209	21.61	nd	78.37	nd	nd	nm	nm
ACT1-2A	First sample	2,100	3	nd	nd	0.0217	21.63	nd	78.33	0.0157	0.0001	nm	nm
ACT1-2B	First sample	2,100	3	nd	nd	0.0222	21.58	nd	78.39	0.0056	0.0001	nm	nm
ACT1-3A	Second sample	1,000	4	0.0191	nd	0.0214	21.47	0.028	78.45	0.0092	nd	nm	nm
ACT1-3B	Second sample	1,000	4	0.0218	nd	0.0217	21.33	0.045	78.58	0.0053	nd	nm	nm
ACT1-3B	Duplicate	1,000	4	0.0212	nd	0.0212	21.34	0.045	78.57	0.0053	nd	nm	nm
ACT1-4A	Third sample	100	5	0.0322	0.0130	0.0213	21.14	0.13	78.63	0.0335	nd	-16.3	-39
ACT1-4B	Third sample	100	5	0.0331	0.0161	0.0226	20.95	0.25	78.70	0.0271	nd	-15.0	-40

Notes:

nd = Indicates non-detect concentrations, concentrations of carbon monoxide and C_2H_4, C_3, C_3H_6, iC_4, iC_5, nC_5, and C_8+ hydrocarbons were non-detect in all samples.
Nm = indicates isotopic measurement not performed for these samples
% - percent
psi – pounds per square inch

At the end of the initial 3-day 2,100 psi test period, concentrations of all gas constituents except C_1 and C_2 hydrocarbons were unchanged from the initial laboratory air concentrations. Subsequent samples collected at 1,000 psi (4 days) and 100 psi (5 days) exhibited decreased oxygen concentrations and increased nitrogen, carbon dioxide, helium, and methane concentrations (**Table VIII-2**). SEM examination of the pre-test and post-test core samples did not identify any textural or mineralogical differences, which is consistent with the small amount of oxygen consumption that occurred during the short test duration.

Delayed ex-solution of reaction products is a likely mechanism to explain the lack of gas composition change after the first 3 days. Depressurization release of natural gas originally trapped within the core sample and an induction (latency) period for the oxygen consumption reaction are additional likely causes of the initially invariant gas composition. Decreasing oxygen concentrations in days 4 and 5 indicate that oxygen was consumed during the test; however, the nature of the oxygen-consuming reaction cannot be determined based only on the gas phase analysis data.

Based on the $\delta^{13}CO_2$ data, a small portion of the carbon dioxide concentrations could be associated with King Island natural gas; however, it is likely that some of the carbon dioxide originated from reaction of the core minerals with oxygen. A likely source of the carbon dioxide is from siderite reaction with acid, with the acid produced from pyrite reaction with oxygen, or from oxidation of iron in siderite with associated release of carbon dioxide. Isotopically, a carbonate source for the carbon dioxide cannot be uniquely demonstrated because the carbon isotopic signature of the siderite is not known.

Based on the results of the 5-day test, a relatively small reduction in oxygen concentration (from an assumed initial concentration of 20% to a final 19.5%) would be predicted for field testing. Such a small change in the oxygen concentration indicates that 5-day cycle times during field testing or full-field operations would be unlikely to significantly reduce oxygen concentrations and that a relatively small amount of oxygen depletion is likely to occur over a reservoir cycle period of one to two weeks.

SEM and XRD analyses and air chamber testing were performed only on MRF injection zone samples consisting mostly of sand (quartz and plagioclase). Because the potentially reactive minerals (iron-bearing clays, pyrite and siderite) are also likely present in the Capay Shale confining zone, there is some potential for oxygen-consuming chemical reactions. However, due to the much lower permeability of the confining zone, injection air penetration into the confining zone and contact with potentially reactive minerals are expected to low.

Additional Testing

Due to the short time frame of the compression test (approximately 90 days) and the use of depleted air during most or all of the test, any negative impacts to the formation and wellbore due to the reactions described above are expected to be limited. One of the objectives of the compression test is to collect data in order to evaluate the potential for these impacts during full-field development. These data collection efforts will include, but may not be limited to, the following:

- Representative formation water samples will be collected during the compression test for laboratory analysis, including for potentially corrosion/scale producing bacteria, to evaluate possible abiotic and biotic chemical impacts to the reservoir and well due to compression testing.

- At periodic intervals during the compression test and the post compression test monitoring period, gas samples will be collected from the I/W wellhead manifold sampling port for fixed gas analyses in order to measure possible compositional changes indicative of abiotic and/or biotic reactions.
- A borehole televiewer could be deployed by wireline in the I/W well to determine the possible presence of corrosion and/or scaling in the tubulars.
- Particulate matter trapped in the filters could be extracted and analyzed using x-ray diffraction to determine the possible presence of secondary minerals produced by oxidation reactions.

References

Allen, R.D., T.J.Doherty, R.L. Erikson and L.E. Wiles (1983). Factors Affecting Storage of Compressed Air in Porous Rock Reservoirs. Battelle Pacific Northwest Laboratory Report PNL-4707, May 1983.

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Succar, S. and Williams, R.H. (2008). Compressed Air Energy Storage: Theory, Resources and Applications for Wind Power. Princeton Environmental Institute, Princeton University.

United States Geological Survey (USGS) (1990). Geochemical and Geophysical Studies of the Reactions of Some Common Minerals with Air: Implications for Oxygen Loss in Compressed Air Energy Storage Reservoirs. Ridley, W.I., et al., Palo Alto, CA. Electric Power Research Institute Project Report No. RP 8000-9. June 1990.

IX. Status of Corrective Action

1. *Report the status of corrective action on defective wells in the area of review.*

As required in UIC Permit R9UIC-CA5-FY13-1 (Section B.3.c), the Step-Rate Test (SRT) / Fall-Off Test (FOT) report, provided in **Appendix V-6B** and summarized in Attachment V, includes a re-calculation of the Zone of Endangering Influence (ZEI). The ZEI re-calculation is presented in the report titled *"Initial ZEI Re-Evaluation using Field Data"*, which is provided as an appendix to the SRT/FOT report.

The UIC permit requires that the extent of the ZEI be re-evaluated and adjusted as appropriate based on the results of the FOT and other field data. If the ZEI and Area of Review (AOR) are adjusted, any additional wells in the ZEI must be evaluated for corrective action. Also, a determination is made whether any of the wells in the existing ZEI must be re-evaluated for corrective action.

In order to re-evaluate the ZEI based on the reservoir data collected from the I/W Well, two additional scenarios were modeled using MODFLOW 2000, which was previously used to simulate pressure buildup due to I/W Well injection of oxygen-depleted and ambient air in the compression testing program. The method and results of the initial modeling, including the features and limitations of this modeling code, are described in Attachment A to the UIC permit application (PG&E, 2014).

The model was adjusted by creating a zone with lower permeability and lower specific storage around the I/W Well in Model Layer 1, corresponding to the proposed injection zone. These localized changes in permeability and specific storage were made based on the analysis of I/W Well sidewall core and FOT data. The additional modeling scenarios incorporate the adjusted permeability and specific storage near the well with two variations of vertical permeability of the aquitards that separate the various sand layers in the MRF. Detailed information regarding the model adjustments, inputs and simulated pressure build-up (depicted in graphs and contour maps) is presented in the ZEI re-evaluation report, provided as an appendix to the SRT/FOT report (**Appendix V-6B**).

The results of the supplemental modeling performed for the ZEI re-evaluation show that pressure buildup in the lower permeability sediments around the I/W Well will be higher than previously predicted; whereas, pressure buildup in the remainder of the reservoir will be within the low end of the previously predicted range. Pressure buildup in the Upper MR2 and Lower MR2 is predicted to be below the normal hydrostatic gradient. Based on this result, adjustment of the ZEI and re-evaluation of corrective action for the wells within the ZEI and AOR is not warranted.

References

PG&E, 2014. Underground Injection Control Permit Application Technical Attachments, PG&E Compressed Air Energy Storage Project Compression Testing Program, King Island Gas Field, San Joaquin County, California, Revised April 18, 2014.

X. Anticipated Maximum Injection Pressure and Flow Rate

1. *Include the anticipated maximum pressure and flow rate at which injection will operate.*

The results of pressure build-up modeling at the I/W well depicted in Graphs 1 and 2 of the report titled *"Initial ZEI Re-Evaluation using Field Data"* (appendix to SRT/FOT report provided in **Appendix V-6B**), predict maximum pressure increases in the I/W Well of approximately 740 to 750 psi above the normal hydrostatic gradient, equivalent to bottom hole pressures (BHPs) exceeding 2,800 psi. This compares to a pressure build-up of approximately 290 to 450 psi above the normal hydrostatic gradient during prior modeling runs described in Attachment A to the UIC permit application (PG&E, 2014). Because the pressure encountered during injection may be higher than previously predicted to achieve the planned flowrates and schedule of the compression test, it will be necessary to increase the Maximum Allowable Injection Pressure (MAIP) based on the results of the SRT.

The fracture gradient calculated based on the SRT Instantaneous Shut-in Pressure (ISIP) is 0.81 psi/foot. Applying a factor of safety of 20% yields a gradient of 0.65 psi/foot and a MAIP at the shoe of the long string casing (4,665 feet TVD) of 3,032 psi (rounded down to 3,000 psi). The pressurized oxygen-depleted air column in the I/W Well is expected to exert a static pressure of approximately 400 psi at the injection zone, indicating a MAIP at the wellhead of approximately 2,600 psi. We therefore request a revision of the UIC permit for the Project to adopt a maximum BHP of 3,000 psi, and a maximum wellhead injection pressure of 2,600 psi.

The maximum anticipated flow rate for the compression test is 13.5 million standard cubic feet per day (MMscfd). The more conservative Sh2Kl modeling scenario predicts a maximum BHP of 2,844 psi at the end of injection for bubble building. This pressure is below the recommended MAIP of 3,000 psi, indicating that a flow of 13.5 MMscfd should not cause an exceedance of the MAIP.

References

PG&E, 2014. Underground Injection Control Permit Application Technical Attachments, PG&E Compressed Air Energy Storage Project Compression Testing Program, King Island Gas Field, San Joaquin County, California, Revised April 18, 2014.